Reference: Section 3: Finance

Q. Volume 1, page 3-40. Footnote 100 refers to a report on supply cost mechanisms, including practices of other investor-owned utilities, that was completed in 2015. Provide an update to this report covering the last five years.

A. Attachment A provides an update to the supply cost mechanism report that was completed in 2015. The update is limited to a review of Canadian public utility practice and the performance of Newfoundland Power's supply cost regulatory mechanisms over the 2016 to 2020 period. It is expected that a fulsome review of Newfoundland Power's supply cost mechanisms will be completed when wholesale costs and rate structures are known following the commissioning of Muskrat Falls.

Newfoundland Power Inc.
Supply Cost Mechansims Update

Supply Cost Mechanisms Update

August 2021

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1.0 BACKGROUND

1.1 Introduction

This report provides an update to the results of a 2015 review of the regulatory mechanisms that affect the power supply costs of Newfoundland Power.

The update includes a survey of supply cost recovery practices of other investor-owned distribution utilities in Canada and a review of the performance of Newfoundland Power's regulatory mechanisms that impact purchased power costs over the 2016 to 2020 period.

The principal supply cost mechanism for Newfoundland Power is its Rate Stabilization Account ("RSA"). The RSA was created primarily as a means of ensuring that variations in Newfoundland and Labrador Hydro ("Hydro") production costs which were captured in Hydro's Rate Stabilization Plan ("RSP") were recovered in, or credited to, Newfoundland Power's customer rates in a timely fashion. The RSA still serves this purpose. The RSA also serves as a means of crediting to, or recovering from, customer rates variations in Newfoundland Power's purchased power expense. This report will consider the RSA principally in the context of Newfoundland Power's purchased power expense and related regulatory mechanisms, not in the context of Hydro's RSP.

The update is limited to the review of the supply cost mechanisms currently in effect. It is expected that a fulsome review will be required when wholesale costs and rate structures are known following the commissioning of Muskrat Falls.

1.2 Newfoundland Power's Supply Costs

Newfoundland Power is dependent upon Hydro for the power supply required by the Company to meet its obligation to serve its customers.[1] Purchased power expense is Newfoundland Power's largest cost, accounting for almost two-thirds of revenue from rates in 2020.

Newfoundland Power's single supply dependence is relatively rare for investor-owned electric utilities in Canada.[2] Currently, the Company effectively recovers its power supply costs through a combination of customer rates and regulatory mechanisms.

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1 Currently, Newfoundland Power purchases approximately 93% of its power supply requirements from Hydro. Newfoundland Power has no practical alternative to Hydro for the additional power supply required to meet an increase in customer load.

2 See the *2022/2023 General Rate Application, Volume 3, Expert Evidence of Concentric Energy Advisors, Comparison to other Canadian Investor-Owned Electric Utilities*, page 69, line 27 which provides *"…Newfoundland Power is uniquely dependent on a single source of electric supply, creating greater supply risk than utilities such as FortisBC, Nova Scotia Power, or the Alberta utilities that rely on a more diverse mix of generation and market sources."*

Table 1 shows revenue and purchased power expense for Newfoundland Power on a ¢ per kWh basis for 2000, 2010 and 2020.

Table 1:
Revenue and Purchased Power Expense
2000, 2010 and 2020
¢ per kWh

	2000	**2010**	**2020**
Revenue	7.65	10.25	12.47
Purchased Power Expense	4.37	6.62	8.18
Purchased Power Expense as % of Revenue	57%	65%	66%

Over the last 20 years, Newfoundland Power's electricity rates and revenues have increased primarily as a result of increased purchased power expense. Over the last 10 years, purchased power expense has increased as a proportion of Newfoundland Power's revenue. Over the last 20 years, on a ¢ per kWh basis, almost 80% of the change in Newfoundland Power's revenues over this period is attributable to increased purchased power expense.[3] Purchased power expense is substantially beyond management control in any given year.

2.0 REGULATORY MECHANISMS

2.1 National Overview

Mechanisms that permit full recovery of energy supply costs by investor-owned distribution utilities are commonplace in Canadian regulatory practice.[4] The widespread use of such regulatory mechanisms simply reflects that, in both the electricity and the gas distribution business, the cost of supply is typically the largest single cost.

Appendix A is a summary of current supply cost recovery practices for regulated investor-owned distribution utilities in Canada.

2.2 Demand Management Incentive Account

In Order No. P.U. 32 (2007), the Board approved a definition of a Demand Management Incentive ("DMI") Account to be included in the Company's system of accounts.

[3] Change in unit supply costs of 3.81¢ divided by change in unit revenues of 4.82¢ equals 79%.
[4] Such regulatory mechanisms also appear to be commonplace in the U.S. See the *2022/2023 General Rate Application, Volume 3, Expert Evidence of Concentric Energy Advisors*, *Comparison to U.S. Electric Utility Proxy Group*, page 76, lines 22 to 26.

The DMI Account is charged or credited with the amount by which the demand supply cost variance exceeds the demand management incentive which is ±1 percent of test year wholesale demand charges.
Table 2 shows a summary of the demand cost variations for the years 2016 through 2020, with a breakdown of the cost (savings) allocation between the Company and its customers.

Table 2:
DMI Account
Demand Cost Variations
($000s)

	2016	**2017**	**2018**	**2019**	**2020**
Demand Cost Variance[5]	(587)	2,856	462	3,445	2,186
Company (Savings) Cost	(587)	728	462	758	755
Customer (Savings) Cost	-	2,128	-	2,687	1,431

Newfoundland Power files an annual application with the Board by March 1st to address the disposition of any balance in the DMI Account. Any required recovery from, or credit to, customers arising from a DMI balance is typically included in the Company's annual RSA adjustment.[6]

2.3 Energy Supply Cost Variance Clause

Changes in the Company's purchased power expense related to variances in customers' load requirements are captured by the energy supply cost variance clause.

Any required credit to, or recovery from, customer rates arising from energy supply cost variances are included in the Company's annual RSA adjustment.

[5] The demand cost variance is derived from test year unit demand cost. Transfers to reserves are on an after-tax basis. Benefits credited to customers through amortizations or through the RSA are effectively on a before-tax basis.

[6] By Order Nos. P.U. 10 (2018), P.U. 11 (2020), and P.U. 14 (2021), the Board approved the recovery from customers of the balance resulting from the operation of the DMI Account in 2017, 2019 and 2020, respectively, through the annual RSA adjustment. Section II(6) of the Rate Stabilization Clause provides for adjustments to the RSA upon order of the Board.

Table 3 shows Newfoundland Power's marginal supply costs from Hydro and the average supply costs recovered in customer rates for 2016 through 2020.

Table 3:
Energy Supply Cost[7]
2016 to 2020
(¢/kWh purchased)

	2016	**2017**	**2018**	**2019**	**2020**
Average	6.379	6.461	6.261	6.543	7.439
Marginal	9.509	9.509	10.422	10.422	18.165
Difference	**(3.130)**	**(3.048)**	**(4.161)**	**(3.879)**	**(10.726)**

Table 3 shows that wholesale energy cost dynamics on the island of Newfoundland have been such that the cost to Newfoundland Power of the additional energy supply required to serve new customers is greater than the average energy supply cost reflected in customer rates.[8] This current annual shortfall is 10.7¢/kWh and is expected to continue, at a minimum, until interconnection to the North American grid.

This shortfall impairs Newfoundland Power's ability to recover not only its purchased power costs from Hydro but also its own costs of providing service. To ensure reasonable recovery by Newfoundland Power of this increased supply cost without the requirement for a general rate application, the Board approved the annual recovery of energy cost variances through the RSA.[9]

Table 4 shows energy supply cost variances captured by the energy supply cost variance clause from 2016 through 2020.

Table 4:
Energy Supply Cost Variances
($000s)

2016	**2017**	**2018**	**2019**	**2020**
3,134	(2,446)	(5,822)	(3,326)	(21,441)

7 Based on January prices.
8 This wholesale energy cost dynamic has existed since the Energy Supply Cost Variance mechanism was initially approved in 2007.
9 This was first approved in Order No. P.U. 32 (2007) and continued by Order No. P.U. 43 (2009).

The $21.4 million energy supply cost variance in 2020 is due to the difference between the marginal and average supply cost rate of 10.7¢/kWh coupled with the decline in energy sales experienced since the Company's last general rate application.[10]

2.4 Weather Normalization Reserve

Newfoundland Power continues to serve a substantial heating load. Variations in weather, therefore, can have a substantial effect on the Company's purchased power expense. The Company's Weather Normalization Reserve normalizes the effects of weather and hydrology on the Company's sales and purchased power expense.[11]

Table 5 shows annual Weather Normalization Reserve transfers from 2016 through 2020.

Table 5:
Weather Normalization Reserve
Transfers (To) From
($000s)

	2016	**2017**	**2018**	**2019**	**2020**
Annual transfers to the Weather Normalization Reserve	1,721	4,771	1,517	5,654	(3,734)
Annual transfers to the RSA	(4,411)	(1,721)	(4,771)	(1,517)	(5,654)

Beginning in 2013, the Board approved, in Order No. P.U. 13 (2013), the transfer of the annual balance in the Weather Normalization Reserve to the RSA.[12]

3.0 CONCLUSION

Newfoundland Power's purchased power expense accounted for approximately 65% of the Company's revenue in 2020. The Company's current supply cost recovery mechanisms essentially provide the Company with the reasonable opportunity to recover this expense.

[10] For example, due to lower energy sales in 2020, Newfoundland Power purchased 5,604.309 GWh from Hydro, or 199.891 GWh less than the 2020 test year forecast of 5,804.200 GWh. The Energy Supply Cost Variance transfer to the RSA on December 31, 2020 was therefore $21.4 million [199.891 GWh x 10.726¢/kWh].

[11] The Weather Normalization Reserve has two components: the Hydro Production Equalization Reserve (the "Hydro Component") and the Degree Day Normalization Reserve (the "Degree Day Component"). The Hydro Component effectively adjusts for the effects on purchased power expense that result from abnormal stream-flows to the Company's hydro-electric plants. The Degree Day Component effectively adjusts for the effects of abnormal weather (i.e., temperature and wind speed) on contribution from sales (i.e. change in revenue from rates less change in purchased power expense). The Hydro Component of the Weather Normalization Reserve was approved in Order No. P.U. 32 (1968) and the Degree Day Component was approved in Order No. P.U. 1 (1974).

[12] By Order Nos. P.U. 12 (2017), P.U. 11 (2018), P.U. 13 (2019), P.U. 10 (2020) and P.U. 13 (2021), the Board approved the disposition to customers of the balance resulting from the operation of the Weather Normalization Reserve in 2016, 2017, 2018, 2019 and 2020, respectively, through the annual RSA adjustment.

Regulatory mechanisms which provide a utility with a reasonable opportunity to recover its prudently incurred supply costs are consistent with both sound public utility regulation and current Canadian practice. Such mechanisms are routinely commented upon favorably by credit rating agencies.[13]

The Company's current supply cost mechanisms specifically meet local regulatory policy objectives and are consistent with current Canadian regulatory practice. It is expected that a fulsome review of Newfoundland Power's supply cost mechanisms will be required when wholesale costs and rate structures are known following the commissioning of Muskrat Falls.

[13] See, for example, *2022/2023 General Rate Application, Volume 1, Application, Company Evidence and Exhibits, Exhibit 4* for the credit opinions of Moody's Investors Services and DBRS.

Supply Cost Recovery Practices for Regulated Investor-owned Distribution Utilities in Canada

Electric Utilities	Province	Supply Cost in Customer Rates	Flow-through Mechanism	Mechanism Description
Maritime Electric	PEI	Yes	Yes	Energy Cost Adjustment Mechanism that provides for recovery or refund to customers of the variation from test year energy supply costs. (See Note 1)
FortisOntario	Ontario	Yes	Yes	Variance account to capture price differentials between the actual supply cost and supply cost reflected in customer rates. (See Note 2)
FortisAlberta	Alberta	No	Not Required	(See Note 3)
ATCO Electric	Alberta	No	Not Required	(See Note 3)
FortisBC	BC	Yes	Yes	A flow-through deferral account that captures certain variances from regulated forecast revenues and other expenses, including those that are not controllable or associated with clean growth capital expenditures, and that do not have separately approved deferral mechanisms, and flows those variances through customer rates in the following year.
Nova Scotia Power	NS	Yes	Yes	Regulatory mechanism to recover fluctuating fuel costs from customers through annual fuel rate adjustments. (See Note 4).
Gas Utilities				
GazMetro	Quebec	Yes	Yes	Énergir, Inc. uses rate stabilization accounts to temper the unpredictable and uncontrollable impacts of temperature changes and wind velocity changes on the activities of the distribution of natural gas in Quebec ("QDA") and Vermont Gas Systems Inc. ("VGS") as well as the impact of natural gas inventory variances on QDA's activities. These regulatory assets and liabilities ("RAL") are amortized over a two-year period as of the year following their initial recognition for QDA and over one year as of the subsequent fiscal year for VGS. (See Note 5)
Enbridge Gas	Ontario	Yes	Yes	The Company records a regulatory or regulatory liability for purchase gas variance. Purchase gas variance is the difference between the actual cost and the approved cost of natural gas reflected in rates. The Company has been granted Ontario Energy Board ("OEB") approval to refund this balance, or collect this balance from, customers on a rolling 12 month basis as part of the Quarterly Rate Adjustment Mechanism ("QRAM") process. (See Note 6).
ATCO Gas	Alberta	No	Not Required	(See Note 3)

AltaGas	Alberta	Yes	Yes	A Gas Cost Recovery Rate (GCRR) is updated monthly to account for the difference between estimated and actual cost of purchasing gas.
FortisBC Energy	BC	Yes	Yes	There are two primary deferral mechanisms in place to decrease the volatility in rates caused by such factors as fluctuations in gas supply costs and the impacts of weather and other changes on use rates. (See Note 7)
Pacific Northern Gas	BC	Yes	Yes	Regulatory mechanisms to mitigate the effect on earnings of volume volatility and natural gas cost volatility. (See Note 8)

Notes:

(1) The Energy Cost Adjustment Mechanism ("ECAM") adjusts for monthly variances from the 9.244 ¢ per kWh test year energy supply cost, and the balance is recovered or refunded, as appropriate, over a rolling 12-month period. The PEI Energy Accord currently stipulates the term of the disposition of the balance related to the ECAM.

(2) The Electricity Distribution Rate Handbook approved by the Ontario Energy Board provides for a purchased power variance/deferral account for distribution utilities to capture price differentials between the actual electricity supply costs and the supply cost reflected in customer rates.

(3) FortisAlberta, ATCO Electric, and ATCO Gas own and operate assets that provide distribution service under Alberta Utilities Commission approved distribution tariffs. Distribution tariffs provide for a recovery of the cost of distribution service including a fair return. Electricity and gas supply costs are not considered a cost of these utilities' provision of distribution service. Supply costs are a separate component on customers' bills.

(4) Nova Scotia Power Inc. ("NSPI") has a Nova Scotia Utility and Review Board ("UARB") approved Fuel Adjustment Mechanism ("FAM"), allowing it to recovery fluctuating Fuel Costs from customers through annual fuel rate adjustments. Differences between prudently incurred Fuel Costs and amounts recovered from customers through electricity rates in a given year are deferred to a FAM regulatory asset or liability and recovered from or returned to customers in a subsequent year.

(5) Énergir Inc. owns a 58% ownership interest in Gaz Métro LNG L.P. ("Gaz Métro LNG"), and the remaining 42% is owned by Investissement Québec.

Énergir Inc. inventories consist mainly of natural gas and also includes supplies and materials inventories. Inventories are measured at the lower of cost and net realizable value. Cost is determined using the weighted average cost method. Énergir L.P. is not authorized to profit from the sale of natural gas. As such, the difference between the supply rates approved by regulatory agencies, as necessary, and the actual cost of supplying natural gas is recognized as an adjustment to direct costs with an offsetting RAL created in accordance with the regulatory mechanism. This mechanism helps to minimize the risks arising from fluctuations in natural gas prices.

(6) On January 1, 2019, Enbridge Gas Distribution Inc. ("EGD") and Union Gas Limited ("Union Gas") amalgamated and have continued from this date as Enbridge Gas.

Prices for natural gas sold are driven by market prices and the QRAM in place that allows for rates to reflect changes in natural gas prices subject to regulatory approval.

(7) The first mechanism relates to the recovery of all gas supply costs through deferral accounts that capture variances (overages and shortfalls) from forecasts in costs incurred and amounts recovered through rates. Balances to be either refunded to or recovered from customers are determined via quarterly application and review by the British Columbia Utilities Commission ("BCUC"). Currently under this mechanism, there are two separate deferral accounts: the Commodity Cost Reconciliation Account ("CCRA") and the Midstream Cost Reconciliation Account ("MCRA").

The second mechanism seeks to stabilize delivery revenues from residential and commercial customers through a deferral account that captures variances in the forecast versus actual customer use rate for residential and commercial customers throughout the year. This mechanism is called the Revenue Stabilization Adjustment Mechanism ("RSAM").

The RSAM, MCRA and CCRA accounts are either refunded to or recovered from customers in rates within 2 years with actual refunds or recoveries dependent upon approved rates and actual gas consumption volumes.

(8) Two rate stabilization mechanisms are used at Pacific Northern Gas.

The first is the Gas Cost Variance Account ("GCVA") which is utilized to record variances in the actual cost of gas and the forecasted cost of gas reflected in customer rates.

The Revenue Stabilization Adjustment Mechanism ("RSAM") adjusts revenue from residential and small commercial customers by a deferral account that records differences between forecast and actual deliveries.

When deliveries to customers vary from forecast, balances accumulate in the accounts which are recovered, or refunded, as appropriate in future rates to residential and small commercial customers.